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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01773A-09-0472 **NOTICE OF FILING REJOINDER TESTIMONY**

Notice is given that Arizona Electric Power Cooperative, Inc. has filed the Rejoinder Testimony of Gary E. Pierson.

RESPECTFULLY SUBMITTED this 6th day of October, 2010.

GALLAGHER & KENNEDY, P.A.

By Michael M. Grant

Michael M. Grant
Jennifer A. Cranston
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Original and 13 copies filed
this 6th day of October, 2010, with:

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REJOINDER TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

October 6, 2010

TABLE OF CONTENTS

Page

REJOINDER TESTIMONY OF GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored Direct, Supplemental Direct and Rebuttal Testimonies for AEPCO in this matter?

A. Yes, I am.

Q. Have you reviewed the Surrebuttal Testimonies of Staff witnesses Messrs. Smith, Antonuk and Kalbarczyk?

A. Yes, I have. My Rejoinder Testimony will respond to various issues raised in their testimonies. I will also discuss the status of the Rural Utilities Service ("RUS") review of the contracts and contract amendments we filed for Commission approval in the Request for Contract Amendment Approvals and Joint Request for Contract/Amendments Approvals on June 2, 2010. Finally, I will present exhibits that summarize AEPCO's final recommendations regarding revenue requirements, proposed forms of a tariff and schedule, Purchased Power and Fuel Adjustment Clause ("PPFAC") bases and recommended rates.

RESPONSE TO MR. SMITH'S SURREBUTTAL TESTIMONY

Q. On surrebuttal, Mr. Smith notes the agreement between Staff and AEPCO on almost all issues and indicates that Staff agrees with AEPCO's normalized annual

rate case expense allowance amount of $160,000. He states at page 3 of his Surrebuttal Testimony that the sole remaining disagreement between Staff and AEPCO is Staff's recommendation of a Debt Service Coverage ("DSC") ratio of 1.40 and AEPCO's recommendation of a 1.32 DSC. Do you agree with Mr. Smith's assessment of this case's status?

A. Yes, I do. AEPCO is requesting a revenue <u>decrease</u> of about $1.172 million, while Staff recommends a revenue <u>increase</u> of slightly more than $230,000. Mr. Smith is correct that the approximately $1.4 million difference is entirely attributable to the DSC recommendations. For reasons I'll discuss shortly—including a quite favorable development which occurred just last month in relation to AEPCO's coal purchases—AEPCO continues to support the DSC recommendation of 1.32.

RESPONSE TO MR. ANTONUK'S SURREBUTTAL TESTIMONY

Q. At page 3 of his Surrebuttal Testimony, Mr. Antonuk recommends the preparation of an action plan by AEPCO in relation to Liberty's recommendations regarding fuel contracting, fuel supply management, gas hedging, power transactions, engineering analysis/plant operations and the PPFAC. Following preparation of that plan, he recommends quarterly reporting concerning implementation to AEPCO's Board and that copies of those reports be filed with the Commission. Please provide AEPCO's response.

A. We agree with Mr. Antonuk's suggestion. AEPCO should be able to file the completed plan by February 1, 2011. In addition, AEPCO proposes to file with the Director of the Utilities Division quarterly reports concerning the action plan until all items are accomplished. In that regard, certain aspects of the plan or the reports concerning it may contain confidential and/or commercially sensitive information. Therefore, we would ask that the Commission authorize in this Order the filing of any such information on a confidential basis. We will also communicate periodically with Staff if action plan implementation difficulties are encountered or changes to it are necessary.

Q. Do you have any other points to make concerning the recommendations?

A. Yes. I want to clarify, as my Rebuttal Testimony indicates, that actions have already been taken or are scheduled to be taken on several of Liberty's recommendations. Briefly, to summarize:

- Concerning the reconciliation of physical/book inventory differences, a team consisting of the individuals identified at page 10 of my Rebuttal Testimony has been formed. It will soon commence the review to determine the cause of the differences, as well as any process improvements which should be made.
- As to the auditing recommendation concerning gas hedging transactions, the Internal Audit Department has placed that recommendation in the 2011 internal audit plan risk analysis.
- The PRM pre-scheduling power requirements issue has been addressed in Exhibit B-1 to Schedule B of the PRM agreements which we submitted for Commission approval on June 2, 2010.
- We also are in the process of undertaking a series of steps to assure the Commission as to the effectiveness of the new PPFAC, including, but not

limited to, scheduling an audit of the clause for next year and conducting more frequent reviews.

- Concerning Liberty's recommendation for more structured plans for outage and maintenance, as well as examination of the root causes of trips, Summary Outage Plans will be prepared five to six months prior to each outage and an action plan has been developed to address the issue of trip causation.
- Finally, my Rebuttal Testimony at pages 16-18 responded to Liberty's PPFAC recommendations, including our recommendations that this Order authorize AEPCO to establish a temporary surcharge mechanism to close out the current clause balances.

These items will be included in the complete action plan which is under development.

RESPONSE TO STAFF'S REVENUE REQUIREMENTS POSITION

Q. At pages 3-4 of his Surrebuttal Testimony, Mr. Antonuk states Staff's surrebuttal position concerning a 1.40 DSC. Please provide AEPCO's rejoinder position on revenue requirements.

A. Mr. Antonuk refers to several issues which were raised by Mr. Vickroy on direct in support of his 1.40 DSC recommendation. As background, before we prepared our rebuttal position, AEPCO carefully reviewed Mr. Vickroy's testimony and his concerns about fuel volatility, the financing costs associated with capital expenditures and increases in post-test year expenses, including expected mercury control costs. AEPCO then met several times with the Member Rates Committee to discuss the adequacy of

AEPCO's position of a 1.275 DSC in light of those concerns. After consideration of Mr. Vickroy's points, AEPCO's management recommended, and AEPCO's Board authorized, increasing our request for margin requirements to a 1.32 DSC level instead of the earlier amended position of 1.275. We continue to believe that a 1.32 DSC—which falls well within Mr. Vickroy's target range of 1.25 to 1.45—will provide adequate revenues and margins. Further, a quite favorable development which occurred about ten days after I filed my Rebuttal Testimony concerning our coal purchases has reinforced that position.

Q. Please discuss this recent development.

A. At page 10 of my August 30 Rebuttal Testimony, I discussed AEPCO's efforts to reduce the coal inventory levels at Apache Station. They included a tentative agreement between CoalSales and AEPCO to defer the delivery of and payment for 162,000 tons to a future year. Those possible deferrals were in response to a *force majeure* situation earlier this summer at the CoalSales mine. About ten days after my testimony was filed, AEPCO and CoalSales representatives met to discuss this *force majeure* situation. But, they were not able to reach a final agreement on either party's deferral proposal. Under the contract, absent a good faith agreement on alternate delivery (which we were not able to reach), CoalSales does not have an obligation to deliver, and AEPCO does not have an obligation to pay for, the coal tonnage impacted by the *force majeure*. CoalSales has calculated AEPCO's share of this impacted tonnage to be 141,100 tons.

Q. Please explain how this positively impacts AEPCO.

A. As a result of not having to take delivery of the 141,100 tons, AEPCO's working capital has been increased by their cost, which is approximately $7.7 million. When I filed my Rebuttal Testimony, we believed this $7.7 million expense would only be <u>deferred</u> until 2011 or 2012. That certainly would have assisted cash flow on a short-term basis, but would not have permanently improved our cash and financial position. Now, because of this *force majeure* development, the $7.7 million expense has instead been permanently <u>avoided</u>. To place that amount in context—as Mr. Minson testified in his Direct Testimony—AEPCO's objective is to build toward $20 million in working capital over the next several years. This $7.7 million avoided cash outlay obviously is a significant step toward that goal and allowed us to pay off the outstanding balance on our line of credit. It also reinforces the sufficiency of our request for a 1.32 DSC and the approximately $2.95 million in annual operating margins it is expected to produce.

Q. Mr. Antonuk also cites Mr. Vickroy's concern about an increase in operating expense resulting from new mercury control expenses as support for the 1.40 DSC recommendation. Will AEPCO be able to recover those new expenses through the PPFAC?

A. Yes. As a result of initial testing, it has been determined that the new mercury control chemical treatment will be applied to the coal at the point at which the coal is conveyed from the stockpile to the coal bunkers. Therefore, the treatment costs are recoverable through AEPCO's PPFAC, which allows for recovery of all costs recorded in RUS Account 501. RUS Account 501-Fuel states in part that, "This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank, or holder of the boiler-house structure."[1] Because the mercury control chemicals will be applied in the handling process before the coal (fuel) enters the bunker, the mercury costs will be recoverable through the PPFAC. Therefore, there is no need to increase the DSC request in anticipation of this expense.

Q. Messrs. Antonuk and Vickroy also note fuel price volatility as a risk to AEPCO's financial status. Please respond.

A. Having coped with the extreme volatility of fuel prices a few years ago, we certainly do not dismiss those concerns. However, the markets have calmed considerably in the wake of the economic turndown and current forward indicators are for continuing, relative price stability. AEPCO has also instituted fuel supply management and gas hedging strategies to help us ameliorate the effects of any price fluctuations. As well, we have two "fixed" price years remaining on our coal contract, which also is a positive, stabilizing factor. Additionally, with Trico's conversion to PRM status, approximately 90% of our Class A member load requirements are now fixed. While that does not remove the volatility risk associated with meeting that load, it has shifted from AEPCO to the PRMs that risk as to any future load growth. Finally, Mr. Antonuk indicates that Staff does support our request to continue the "efficacy option" of the last rate order.

[1] 7 CFR 1767-Accounting Requirements for RUS Electric Borrowers, Subpart B-Uniform System of Accounts, § 1767.27. (Emphasis supplied.)

That will continue to allow us promptly to bring to the Commission requests for reviews and modifications of cost recovery under the PPFAC should circumstances require such action. Given all of these factors, we believe we do have sufficient protections in place to manage fuel price volatility without the necessity of increasing rates now to accommodate a 1.40 DSC.

Q. **Finally, Messrs. Antonuk and Vickroy cite post-test year capital expenditures in their testimonies as a justification for a higher DSC.**

A. AEPCO agrees that the financing costs associated with capital expenditures will result in increased revenue requirements pressure. That factor, however, is a primary reason why we increased our DSC request from 1.275 to 1.32 on rebuttal. Given all of these considerations, we continue to urge that the Commission approve the 1.32 DSC.

CONTRACTS AND CONTRACT AMENDMENTS STATUS

Q. **Please discuss the status of the RUS review of the contracts and contract amendments which AEPCO filed for Commission approval in this rate case docket on June 2, 2010 (the "Contracts").**

A. Briefly, to summarize, the Contracts we filed in June primarily provide for three things: (1) Trico's conversion to PRM status, which we are reflecting in our proposed rates;[2] (2) certain changes to cost allocation and rate design methods, which are included in the rates we have proposed and which have been reviewed by Staff;[3] and (3) the changes to

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[2] *See* GEP-5; Company Rejoinder Column.

[3] Kalbarczyk Surrebuttal Testimony; pp. 2-5 and Table II.

the PPFAC, "whose purpose is to align amounts recovered from individual members more closely with the hourly costs they impose on AEPCO."[4] AEPCO has also filed those Contracts with RUS. We are scheduled to meet with RUS on October 20, 2010 to discuss them. AEPCO has requested that RUS complete its review promptly and approve the Contracts. AEPCO also requests that the Commission approve the Contracts in this Order.

SUMMARY OF REQUESTS

Q. Have you prepared exhibits which summarize AEPCO's rejoinder position?

A. Yes, I have. Exhibit GEP-4 sets forth AEPCO's and Staff's positions as the case has moved from direct to rejoinder. As shown on Exhibit GEP-4, Column 5, AEPCO's rejoinder position remains the same as our rebuttal position. We request a 0.70% decrease over test year present rates based upon a DSC of 1.32. This would produce operating revenues of approximately $177.6 million; net margins of about $4.1 million; TIER and DSC ratios of 1.375 and 1.32, respectively; and a return of 6.97% on the fair value rate base of just over $211.8 million.

Q. Have you also prepared an exhibit which shows AEPCO's requested rates?

A. Yes, I have. As noted in Mr. Kalbarczyk's Surrebuttal Testimony,[5] Staff and AEPCO agree on cost of service and rate design issues. Therefore, the only difference between AEPCO's rejoinder rates and Staff's surrebuttal rates is the $1.4 million difference in our

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[4] Antonuk Direct Testimony, p. 14, ll. 1-3.

[5] Kalbarczyk Surrebuttal Testimony, p. 5.

revenue requirements positions. Exhibit GEP-5 summarizes the proposed rates associated with the various positions set forth on Exhibit GEP-4. Column 6 shows the rates that AEPCO requests the Commission approve. In addition, the exhibit sets forth the recommended PPFAC bases based upon AEPCO's rejoinder position.

Q. **Have you also prepared a form of all-requirements tariff and a partial-requirements schedule?**

A. Yes. We have previously provided these forms to Staff. They are attached with minor modifications and also include AEPCO's recommended rates. Exhibit GEP-6 is AEPCO's proposed rate tariff and PPFAC language for the collective ARMs and Exhibit GEP-7 provides the schedule and PPFAC language for AEPCO's PRMs.

Q. **Can you estimate the impact that AEPCO's proposed rates would have on the retail member/owner's bill?**

A. As mentioned in Mr. Minson's Direct Testimony, it is difficult to provide precise estimates, because the distribution cooperatives have different retail rates for different classes, as well as varying rate structures and purchased power adjustment mechanisms. However, generation service accounts for about 55% of the costs of the total delivered rate at retail. Assuming a residential rate of 14 cents per kWh, an average eight cents of that rate would be attributable to AEPCO's generation service. Therefore, we estimate that an ARM residential consumer using 1,000 kWh per month would see about a $1.80 <u>decrease</u> in the monthly bill; a Mohave Electric Cooperative residential consumer using the same amount would see about a $1.80 <u>increase</u>; a Sulphur Springs Valley Electric

Cooperative residential consumer using the same amount would see about a $0.50 increase; and a Trico Electric Cooperative residential consumer using that same 1,000 kWh would see about a $4.20 decrease in the monthly bill as a result of this rate request. When these approximate increases or decreases would be flowed through to the retail level would also be dependent on the terms and status of each distribution cooperative's adjustment clause.

Q. Please provide AEPCO's recommendation to establish a temporary surcharge mechanism for closing out the existing fuel bank balances as of the effective date of the recommended rates.

A. As mentioned in my Rebuttal Testimony on pages 17-18, AEPCO proposes a temporary surcharge of 1.12 mills per kWh for ARMs and 1.68 mills per kWh for PRMs, effective at the same date as the new rates authorized in the Order. These temporary surcharges will remain in effect until AEPCO collects each member's remaining under-collected balances under the current clause. Because Trico has participated in the current clause as an ARM, AEPCO recommends using the ARM temporary surcharge for Trico as well. AEPCO will account for the collections on a member-by-member basis, so that no member under- or overpays its contribution to the under-collected total bank. In the event that any member has contributed too much to the under-collected bank, the same temporary surcharge rate will be used to refund that overpayment. At the end of the month following collection (or return) of all under-collections (or over-collections), we will file a report in this docket summarizing surcharge close-out results on a member-by-member and total basis.

Q. Does AEPCO also request that the Order authorize continuation of the so-called "efficacy" provision in relation to the PPFAC?

A. Yes. We recommend the language used at page 16 of Decision No. 68071: "IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. may file a request that the Commission review the efficacy of the [PPFAC] with Arizona Electric Power Cooperative, Inc.'s submission of any semi-annual... report required by this Decision." As discussed at page 18 of my Rebuttal Testimony, we recommend that the first semi-annual fuel adjustor be filed on September 1, 2011, to become effective on October 1, 2011.

Q. Finally, Mr. Pierson when does AEPCO request that the new rates become effective?

A. We ask that the Contracts be approved and the new rates take effect with usage from and after January 1, 2011. However, as I mentioned previously, we must have RUS approval for the Contracts, as well as for Trico's conversion to PRM status, prior to the new rates taking effect. If we do not receive RUS approval by December as we expect, we will promptly notify the Commission and request that the rates' effective date be postponed accordingly.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT GEP-4

Arizona Electric Power Cooperative, Inc.

Comparison of Increase in Gross Revenue Requirement

Test Year Ended March 31, 2009

Line No.	Description	Col. 1 Company As Amended Position	Col. 2 Staff Direct Position	Col. 3 Company Rebuttal Position	Col. 4 Staff Surrebuttal Position	Col. 5 Company Rejoinder Position
1	Summary of Revenue Increase Proposed:					
2	Proposed Revenue Increase	$ (96,754)	$ 231,014	$ (1,172,317)	$ 231,014	$ (1,172,317)
3	Revenues in Test Year - Present Rates	$ 166,618,639	$ 166,618,639	$ 166,618,639	$ 166,618,639	$ 166,618,639
3	Revenue Increase Percentage	-0.06%	0.14% (1)	-0.70%	0.14%	-0.70%
4						
5	Pro Forma Statement of Operations					
6	with Proposed Rates:					
7	Operating Revenues	$ 178,665,925	$ 178,993,693	$ 177,590,362	$ 178,993,693	$ 177,590,362
8	Operating Expense	164,623,661	162,820,299	162,820,299	162,820,299	162,820,299
9	Electric Operating Margins	14,042,264	16,173,394	14,770,063	16,173,394	14,770,063
10	Interest & Other Deductions	11,917,826	11,822,642	11,822,642	11,822,642	11,822,642
11	Operating Margins	2,124,438	4,350,752	2,947,421	4,350,752	2,947,421
12	Non-Operating Margins	1,112,155	1,112,155	1,112,155	1,112,155	1,112,155
13	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
14						
15	Times Interest Earned Ratio:					
16	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
17	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194	10,812,194	10,812,194
18	Total	$ 14,048,787	$ 16,275,101	$ 14,871,770	$ 16,275,101	$ 14,871,770
19	Times Interest Earned Ratio	1.299	1.505	1.375	1.505	1.375
20						
21	Debt Service Coverage Ratio:					
22	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
23	Depreciation & Amortization	8,348,168	8,317,632	8,317,632	8,317,632	8,317,632
24	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194	10,812,194	10,812,194
25	Total	$ 22,396,955	$ 24,592,733	$ 23,189,402	$ 24,592,733	$ 23,189,402
26						
27	Interest on Long Term Debt	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
28	Principal Payments	6,754,044	6,754,044	6,754,044	6,754,044	6,754,044
29	Debt Service	$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238
30	Debt Service Coverage Ratio	1.275	1.400	1.320	1.400	1.320
31						
32	Return on Fair Value Rate Base:					
33	Electric Operating Margins	$ 14,042,264	$ 16,173,394 (1)	$ 14,770,063	$ 16,173,394	$ 14,770,063
34	Rate Base	$ 231,844,975	$ 211,802,594	$ 211,802,594	$ 211,802,594	$ 211,802,594
35	Return on Fair Value Rate Base	6.06%	7.64% (1)	6.97%	7.64%	6.97%

(1) Per Direct Testimony of Dennis M. Kalbarczyk.

EXHIBIT GEP-5

Exhibit GEP-5

Arizona Electric Power Cooperative, Inc.

Comparison of Proposed Rates & PPFAC Bases

Test Year Ended March 31, 2009

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
Description	**Company Current Rates**	**Company As Amended Position Supplemental (2)**	**Staff Direct Position (3)**	**Company Rebuttal Position**	**Staff Surrebuttal Position**	**Company Rejoinder Position**
Collective All-Requirements Members: (1)						
Demand Rate $/kW	$ 14.98	N/A	N/A	N/A	N/A	N/A
Fixed Charge - $/mo.		$ 232,978	$ 931,105	$ 238,793	$ 251,168	$ 238,793
O&M Charge - $/mo.		$ 436,144	$ 1,178,484	$ 414,019	$ 414,019	$ 414,019
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03157	$ 0.03234	$ 0.03156	$ 0.03156	$ 0.03156
Other Resources $/kWh		$ 0.06069	$ 0.06746	$ 0.06170	$ 0.06170	$ 0.06170
PPFAC Bases: (4)						
Current $/kWh	$ 0.01687					
Base Resources $/kWh		$ 0.03377		$ 0.03361		$ 0.03361
Other Resources $/kWh		$ 0.07634		$ 0.07941		$ 0.07941
Partial-Requirements Members:						
Mohave Electric Cooperative						
Fixed Charge - $/mo.	$ 855,113	$ 709,721	$ 764,975	$ 727,283	$ 764,976	$ 727,283
O&M Charge - $/mo. (Present $/kW)	$ 7.26	$ 1,323,724	$ 1,274,882	$ 1,274,882	$ 1,274,882	$ 1,274,882
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03216	$ 0.03215	$ 0.03215	$ 0.03215	$ 0.03215
Other Resources $/kWh		$ 0.06879	$ 0.06879	$ 0.06879	$ 0.06879	$ 0.06879
PPFAC Bases: (4)						
Current $/kWh	$ 0.01603					
Base Resources $/kWh		$ 0.03331		$ 0.03330		$ 0.03330
Other Resources $/kWh		$ 0.07504		$ 0.06971		$ 0.06971
Sulphur Springs Valley						
Fixed Charge - $/mo.	$ 757,429	$ 628,440	$ 677,366	$ 643,991	$ 677,366	$ 643,991
O&M Charge - $/mo. (Present $/kW)	$ 7.26	$ 1,172,125	$ 1,128,876	$ 1,128,876	$ 1,128,876	$ 1,128,876
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03230	$ 0.03229	$ 0.03229	$ 0.03229	$ 0.03229
Other Resources $/kWh		$ 0.06676	$ 0.06676	$ 0.06676	$ 0.06676	$ 0.06676
PPFAC Bases: (4)						
Current $/kWh	$ 0.01603					
Base Resources $/kWh		$ 0.03338		$ 0.03337		$ 0.03337
Other Resources $/kWh		$ 0.07775		$ 0.07241		$ 0.07241
Trico Electric Cooperative						
Demand Rate per kW	$ 14.98	N/A	N/A	N/A	N/A	N/A
Fixed Charge - $/mo.		$ 629,365	N/A	$ 646,435	$ 679,937	$ 646,435
O&M Charge - $/mo. (Present $/kW)		$ 793,509	N/A	$ 764,465	$ 764,465	$ 764,465
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03234	N/A	$ 0.03238	$ 0.03238	$ 0.03238
Other Resources $/kWh		$ 0.06612	N/A	$ 0.06604	$ 0.06604	$ 0.06604
PPFAC Bases: (4)						
Current $/kWh	$ 0.01687					
Base Resources $/kWh		$ 0.03331		$ 0.03336		$ 0.03336
Other Resources $/kWh		$ 0.07634		$ 0.09084		$ 0.09084

1) The Fixed Charge and the O&M Charge will be apportioned among the CARMs and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of the CARMs' 12-month rolling average demand.

2) Amended Filing initially included Trico as part of the CARMs. The Company subsequently filed rates that treated Trico as a PRM pursuant to a contract submitted for ACC approval.

3) Staff witness Kalbarczyk did not develop rates for Trico as a PRM in his direct testimony.

4) Staff witness Kalbarczyk did not take issue with the Company's derivation of the PPFAC bases.

EXHIBIT GEP-6

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

TARIFF

PERMANENT

Effective Date: January 1, 2011

AVAILABILITY

Available to all cooperative associations which are or shall be collective all-requirements Class A members ("CARM") of the Arizona Electric Power Cooperative, Inc. ("AEPCO").

MONTHLY RATE (BILLING PERIOD)

Electric power and energy furnished under this Tariff will be subject to the rates set forth in the attached Exhibit A and the terms set forth herein in addition to any applicable terms set forth in the Member's Wholesale Power Contract.

Billing Month – The first calendar month preceding the month the bill is rendered.

Demand Overrun Adjustment – If, in any hour, the CARM's metered load exceeds its Allocated Capacity, then AEPCO shall compute a Demand Overrun Adjustment for the CARM and each Member shall be charged a portion of such Demand Overrun Adjustment in proportion to that Member's demand ratio share. Such Demand Overrun Adjustment shall equal the product of the CARM's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	Demand Overrun Adjustment Factor,
mbdkW	=	Metered kW of CARM, and
AC	=	Allocated Capacity of CARM, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Resources Energy Rate.

Power Factor – Each Member shall maintain Power Factor at the time of maximum demand as close to unity as possible. If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to the Member. The Power Factor Adjustment shall be the product of the Member's power factor adjustment (as set forth below) multiplied by the quotient of the Member's demand ratio share of the CARM O&M Charge divided by the sum of the CARM's 12-month rolling average demand. The power factor adjustment shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW,
mkW	=	Member Metered kW,
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

The provisions of the power factor adjustment may be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Capacity and Energy Below Allocated Capacity – If CARM is utilizing a Future Resource, Supplemental Purchase or S&G PPA in any hour to serve Native Load and CARM fails to take its required share of Minimum Base Capacity or Minimum Other Capacity, CARM shall pay a charge as set forth in Section 2.4 of Rate Schedule A to the Member's Wholesale Power Contract.

Taxes – Bills rendered are subject to adjustment for all federal, state and local government taxes or levies, including any taxes or levies imposed as a carbon tax or "cap and trade" or other carbon assessments system imposed on electricity sales or electricity production and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Transmission and Ancillary Service Charges – Each Class A member shall also be billed by AEPCO for charges AEPCO incurs for the transmission of power and energy to the Class A member's delivery point(s). Such charges will be assessed to the Class A member at the rates actually charged AEPCO by the transmission provider and others for transmission service and the provision of ancillary services.

Power Cost Adjustor Rates

"Base Resources" are defined as (1) AEPCO's Steam Turbine Units 2 and 3, (2) power purchased under contract from the Western Area Power Administration and (3) economy purchases displacing base resources generation.

"Other Resources" are defined as (1) AEPCO's generation units other than Steam Turbine Units 2 and 3, (2) power purchased under contracts which serve the combined scheduled loads of AEPCO's Class A members plus power purchased under contract and economy energy purchases (other than economy purchases displacing base resources generation) made for the purpose of meeting the scheduled load requirements of all Class A members and (3) power purchased under contracts or resources which have been acquired to serve Class A Member load and which the Member has expressly agreed to in a participation agreement.

The monthly bill computed under this Tariff shall, using the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh derived from each resource type by the applicable Power Cost Adjustor Rate for Base Resources and Other Resources where:

<u>Base Resources Adjustor Rate</u>

BF = (BPC + BBA) - $.003361

BF = Base Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BPC = The Commission-allowed pro forma fuel costs of Base Resources generation, the purchased power costs of Base Resources and wheeling costs associated with Base Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BBA = The "Base Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Base Resources. The BBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Base Resources kWh energy sales.

Allowable Base Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 2 and 3 as recorded in RUS Account 501, plus

B. The actual costs associated with Base Resources power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis to substitute for higher cost Base Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Base Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the collective all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Base Resources power and energy as recorded in RUS Account 447, less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Base Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

Other Resources Adjustor Rate

OF = (OPC + OBA) - $0.07941

OF = Other Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OPC = The Commission-allowed pro forma fuel costs of Other Resources generation, Other Resources purchased power and wheeling costs associated with Other Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OBA = The "Other Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Other Resources. The OBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Other Resources kWh energy sales.

Allowable Other Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 1, 4, 5 and 6 as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with Other Resources purchased power for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of Other Resources energy purchased when such energy is purchased on an economic dispatch basis. Included therein are such costs as those charged for economy energy purchases and the charges resulting from a scheduled outage of Other Resources generation units. All such kinds of Other Resources energy being purchased by AEPCO to substitute for its own higher cost Other Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Other Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the collective all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Other Resources power and energy as recorded in RUS Account 447, less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Other Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rates as specified herein based upon a rolling 12-month average of allowable fuel, purchased power and wheeling costs for the BPC and the OPC plus the bank balance amortization component for the BBA and OBA. AEPCO shall initially file by September 1, 2011 and thereafter on March 1 or September 1 of the month preceding the effective date of the revised Power Cost Adjustor Rates (i.e., April 1 or October 1): (1) calculations supporting the revised Adjustor Rates with the Director, Utilities Division, and (2) a Tariff reflecting the revised Adjustor Rates with the Commission which shall be effective for billings after the first day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

EXHIBIT A

Effective Date	January 1, 2011*
Collective All-Requirements Members:	
Total Fixed Charge/Month	$238,793**
Total O&M Charge/Month	$414,019**
Base Resources Energy Rate – $/kWh	$0.03156
Other Resources Energy Rate – $/kWh	$0.06170

Base Resources Power Cost Adjustor Rate – $/kWh $0.00000***
Other Resources Power Cost Adjustor Rate – $/kWh $0.00000***

* Rates are effective for service provided on and after this date.

** The Total Fixed Charge and the Total O&M Charge will be apportioned among the CARMs and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of the CARMs' 12-month rolling average demand.

*** Effective January 1, 2011 and determined and revised as set forth in the Tariff.

EXHIBIT GEP-7

Arizona Electric Power Cooperative, Inc.

Partial-Requirements Schedule
Rates and Fixed Charge
(Effective January 1, 2011)

Service provided to Mohave Electric Cooperative, Inc. ("MEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Trico Electric Cooperative, Inc. ("Trico") by the Arizona Electric Power Cooperative, Inc. ("AEPCO") under the Partial Requirements Capacity and Energy Agreements shall be at the rates set forth in the attached Exhibit A and subject to the terms set forth herein in addition to any applicable terms set forth in the Members' Partial Requirements Capacity and Energy Agreement.

Billing Month – The first calendar month preceding the month the bill is rendered.

Demand Overrun Adjustment – If, in any hour, (i) Member's scheduled load (if Member is not in AEPCO's Control Area) or (ii) Member's metered load less capacity obtained from sources outside the Dispatch Pool (if Member is in AEPCO's Control Area) exceeds its Allocated Capacity, then Member shall be charged a Demand Overrun Adjustment. Such Demand Overrun Adjustment shall equal the product of Member's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	Demand Overrun Adjustment Factor,
mbdkW	=	Member Schedule in kW or Metered kW less capacity from sources outside the Dispatch Pool, as applicable, and
AC	=	Allocated Capacity of Member, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Resources Energy Rate.

Power Factor – Each Member shall maintain Power Factor at the time of maximum demand as close to unity as possible. If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member's peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to the Member. The Power Factor Adjustment shall be the product of the Member's power factor adjustment (as set forth below) multiplied by the quotient of the Member's O&M Charge divided by the sum of the Member's 12-month rolling average demand. The power factor adjustment kW shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW,
mkW	=	Member Metered kW,
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

The provisions of the power factor adjustment may be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Taxes – Bills rendered are subject to adjustment for all federal, state and local government taxes or levies, including any taxes or levies imposed as a carbon tax or "cap and trade" or other carbon assessments system imposed on electricity sales or electricity production and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Power Cost Adjustor Rates

"Base Resources" are defined as (1) AEPCO's Steam Turbine Units 2 and 3, (2) power purchased under contract from the Western Area Power Administration and (3) economy purchases displacing base resources generation.

"Other Resources" are defined as (1) AEPCO's generation units other than Steam Turbine Units 2 and 3, (2) power purchased under contracts which serve the combined scheduled loads of AEPCO's Class A members plus power purchased under contract and economy energy purchases (other than economy purchases displacing base resources generation) made for the purpose of meeting the scheduled load requirements of all Class A members and (3) power purchased under contracts or resources which have been acquired to serve Class A Member load and which the Member has expressly agreed to in a participation agreement.

The monthly bill computed under this Tariff shall, using the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh derived from each resource type by the applicable Power Cost Adjustor Rate for Base Resources and Other Resources where:

Base Resources Adjustor Rate

BF = (BPC + BBA) - BFB

BF = Base Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BPC = The Commission-allowed pro forma fuel costs of Base Resources generation, purchased power costs of Base Resources and wheeling costs associated with Base Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BBA = The "Base Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Base Resources. The BBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Base Resources kWh energy sales.

BFB = The Base Resources Fuel Base or BFB is $0.03330 for MEC, $0.03337 for SSVEC and $0.03336 for Trico.

Allowable Base Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 2 and 3 as recorded in RUS Account 501, plus

B. The actual costs associated with Base Resources power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis to substitute for higher cost Base Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Base Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Base Resources power and energy as recorded in RUS Account 447, and less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Base Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

<u>Other Resources Adjustor Rate</u>

OF = (OPC + OBA) - OFB

OF = Other Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OPC = The Commission-allowed pro forma fuel costs of Other Resources generation, Other Resources purchased power and wheeling costs associated with Other Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OBA = The "Other Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Other Resources. The OBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Other Resources energy sales.

OFB = The Other Resources Fuel Base or OFB is equal to $0.06971 for MEC, $0.07241 for SSVEC and $0.09084 for Trico.

Allowable Other Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 1, 4, 5 and 6 as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with Other Resources purchased power for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of Other Resources energy purchased when such energy is purchased on an economic dispatch basis. Included therein are such costs as those charged for economy energy purchases and the charges as a result of a scheduled outage of Other Resources generation units. All such kinds of Other Resources energy being purchased by AEPCO to substitute for its own higher cost Other Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Other Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Other Resources power and energy as recorded in RUS Account 447, and less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Other Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rates as specified herein based upon a rolling 12-month average of allowable fuel, purchased power and wheeling costs (BPC and OPC) plus a bank balance amortization component (BBA and OBA). AEPCO shall initially file by September 1, 2011 and thereafter on March 1 or September 1 of the month preceding the effective date of the revised Power Cost Adjustor Rates (i.e., April 1 or October 1): (1) calculations supporting the revised Adjustor Rates with the Director, Utilities Division, and (2) a Tariff reflecting the revised Adjustor Rates with the Commission which shall be effective for billings after the first day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

EXHIBIT A

Effective Date	January 1, 2011*		
Partial Requirements Members:	MEC	SSVEC	Trico
Fixed Charge – $/month	$727,283	$643,991	$646,435
O&M Charge – $/month	$1,274,882	$1,128,876	$764,465
Base Resources Energy Rate – $/kWh	$0.03215	$0.03229	$0.03238
Other Resources Energy Rate – $/kWh	$0.06879	$0.06676	$0.06604

MEC

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

SSVEC

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

Trico

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

* Rates are effective for service provided on and after this date.
** Effective January 1, 2011 and determined as set forth in the Tariff.